COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

D.T.E. 03-40

BOSTON GAS COMPANY
d/b/a
KeySpan Energy Delivery New England

DIRECT TESTIMONY OF LEE SMITH
LACAPRA ASSOCIATES

On behalf of

THE OFFICE OF THE ATTORNEY GENERAL

July 7, 2003

I. INTRODUCTION

Q. WHAT IS YOUR NAME AND BUSINESS ADDRESS?

A. My name is Lee Smith, and I work for La Capra Associates, 20 Winthrop Square, Boston, Massachusetts.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of the Massachusetts Office of the Attorney General.

Q. PLEASE DESCRIBE YOUR BACKGROUND AND EXPERIENCE.

A. I am a Managing Consultant and Senior Economist at La Capra Associates. I have been with this energy planning and regulatory economics firm for 19 years. I have prepared testimony on rates in 12 states and before the Federal Energy Regulatory Commission. I have testified previously before the Massachusetts DTE in both gas and electric cases. Prior to my employment at La Capra Associates, I was Director of Rates and Research, in charge of gas, electric, and water rates, at the Massachusetts Department of Public Utilities. Prior to that period, I taught economics at the college level. My resume is attached as Attachment LS-1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I am testifying on the Company's proposal for ratemaking for the next 5 years, which is based on a performance based rate (PBR) formula.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. The PBR formula proposed by the Company presents significant risks to customers and little prospect of benefits. The proposed adjustment to the inflation index is based on a number of "black box" analyses, and neither these analyses nor their rationale to justify a very small consumer dividend are well supported. On this weak basis the Company proposes that it be allowed to increase rates by more than the rate of escalation in Gross Domestic Product. Given these weaknesses and the absence of a consumer dividend, I would recommend rejection of the proposed PBR plan and a return to cost of service regulation of the Company's rates. In the alternative, if the DTE finds that PBR is warranted, the formula should remain the same as in the previous PBR plan; that is, rates should change at the rate of the Gross Domestic Price Inflator less 0.5%. The proposed Earning Sharing mechanism should also be adopted. In my testimony, I provide support for this formulation.

Q. MS. SMITH, HOW IS THE BALANCE OF YOUR TESTIMONY ORGANIZED?

A. In Section II, I describe the Company's PBR proposal. This is followed by separate discussions of various aspects of the Company proposal, beginning with a discussion of productivity change in Section III. Input prices changes are discussed in Section IV. The proposed consumer dividend and the study intended to justify it are the subject of Section V. In Section VI, I discuss the expected benefits and experience elsewhere with PBR. Finally, Section VII contains my recommendations.

II. <u>COMPANY PROPOSAL</u>

Q. WHAT HAS THE COMPANY PROPOSED AS A METHODOLOGY FOR FUTURE RATEMAKING?

A. The Company proposes that same basic formula that existed in the PBR plan that was in effect from 1997-2001, in which rates adjust annually, with the adjustment percentage determined by the Gross Domestic Product Price Inflator ("GDP-PI") minus an X factor. Boston Gas proposes that a negative X factor (-0.2%) be subtracted from the GDP-PI adjustment. Thus, Boston Gas' PBR formula will result in gas delivery rates increasing at a rate of 0.2% more than the general inflation rate [(GDP-PI)-(-0.2%)]. The X factor is developed by considering such matters as expected productivity gains and the relationship between gas input prices and other input prices.

Q. IS THE COMPANY'S PROPOSAL UNUSUAL?

A. Yes. Normally, the overall adjustment to rates resulting from PBR is less than the measure of inflation used as a guideline. That is, once the base rate is established for the first year, it is typical that the annual percentage change is less than the inflation rate. In fact, I know of no PBR plan in which this is not the case.

Q. WHAT IS THE COMPANY'S STATED BASIS FOR THE PROPOSED ADJUSTMENT TO THE INFLATION INDEX, OR THE X FACTOR?

A. Dr. Lawrence Kaufmann of Pacific Economics Group ("PEG") presented testimony on the development of the X factor. The proposed X factor adjusts the Gross Domestic Product Price Inflator for the sum of three separate items: 1) the relationship between gas industry [1]productivity growth and productivity growth in the overall economy; 2) the relationship between gas industry input prices and overall economy prices; and 3) a consumer dividend. The first two adjustments are necessary because the GDP-PI is a measure of change in output prices in the whole economy. Changes in output prices are the result of both changes in input prices and in productivity. Since it is likely that changes in input prices for the gas industry or productivity changes for the gas industry are different from these factors for the overall economy, the GDP-PI must be adjusted to account for them. These adjustments produce an estimate of how we would normally expect gas delivery service prices to change.

Q. PLEASE CONTINUE.

[1] Throughout this testimony "Gas industry" refers to the distribution portion of the gas industry.

A. The first factor, the productivity index, reflects whether productivity in the gas industry has generally increased at a rate greater than, equal to, or less than changes in productivity in the overall economy. The second factor, the input price index, should indicate how the rate of change in prices of inputs used by gas utilities compares to the general price deflator. The overall increase in output prices is a result of input price increases, reduced by productivity gains. The third, the consumer dividend, is intended "to reflect the expectation that TFP [total factor productivity] growth will increase under PBR" (Kaufmann, p. 6).

Dr. Kaufmann of PEG provides testimony on several analyses that develop estimates of these factors. These consist of a price input study, a productivity study, and an analysis of gas utility costs.

III. ANALYSIS OF PRODUCTIVITY DIFFERENTIAL

Q. PLEASE DESCRIBE THE PEG PRODUCTIVITY STUDY AND RESULTS.

A. Since the Company's PBR begins with an index of overall output prices, gas prices would differ from this index if the rate of productivity change in the gas industry were different from productivity change in the overall economy. PEG relied on the Bureau of Labor Statistics ("BLS") estimate of TFP (which the BLS called Multi-Factor Productivity), for the U.S. private business sector as the measure of productivity change in the overall economy. PEG produced a productivity study that estimated the TFP growth of 16 gas utilities in the Northeast. Dr. Kaufmann testifies that the reason for limiting the productivity study to this sample was that "cost and demand pressures may differ regionally, which would affect both input and output growth." A comparison of these two measures over the period 1990-2000 indicates that the productivity increase of these gas utilities was 0.45 percentage points less annually than the productivity measure for the private business sector.

Q. EXACTLY HOW WAS GAS PRODUCTIVITY IN THE NORTHEAST ESTIMATED?

A. PEG gathered data from 16 gas utilities in the Northeast. Excluded were 34 other gas utilities in the region. From other research, PEG estimated weights for the number of customers served and total gas throughput, which were applied to these output quantities to derive a total measure of output. Inputs for each utility included all of booked labor costs, all remaining non-gas operating and maintenance costs, and a PEG estimated capital cost. These three components of cost were then weighted to produce a single input cost index. The difference between the output index and the input index was then interpreted as the difference in total factor productivity.

Q. DO THE CLAIMED DIFFERENT "COST AND DEMAND PRESSURES" NECESSARILY MEAN THAT NATIONWIDE DATA WOULD NOT BE USEFUL?

A. No. The PEG productivity study is used to compare productivity growth rates between the gas industry and total private business sector. The factors that Dr. Kaufmann testifies contribute to productivity gains include technological change, economies of scale, the elimination of inefficiencies, and the degree of capacity utilization. These factors do not have obvious regional characteristics and, indeed, he has not stated directly that they do.

I am not sure what Dr. Kaufmann means by "cost pressures", although another PEG study appears to find that gas company costs are higher in the Northeast than in the rest of the country. Even if this is true, it does not follow that higher costs in one region would affect the <u>rate of change</u> in productivity. What matters is not the level of gas utility costs but the rate at which they have changed over the period of the productivity study; and only if one could demonstrate that there have been differences – or that there are strong reasons to anticipate them ---would there be a rationale to study only the New England region. At a minimum, one would expect that there are reasonable comparisons to be made – and, hence, data to draw on – from regions throughout the country with comparable weather, especially during the winter months.

In addition, Dr. Kaufmann's concern about different "cost pressures" between regions makes little sense because much of the measurement of inputs used in the TFP study is based on estimation techniques that do not reflect different costs between utilities, let alone between regions. Specifically, PEG's analysis turns capital investment into a capital services cost on the basis of return and depreciation rates that are the same for all utilities.

Q. **HAS THERE BEEN ANY DEMONSTRATION THAT THE SAMPLE OF 16 NORTHEAST UTILITIES IS REPRESENTATIVE OF PRODUCTIVITY CHANGE IN THE GAS INDUSTRY?**

A. No, there has not been. No evidence has been presented to demonstrate that the 16 utilities in the Northeast are representative of the 50 utilities, or that smaller gas utilities would have different rates of productivity growth. Nor has there been any evidence that the factors that result in productivity growth are different in the Northeast than in the rest of the country.

Q. **DID PEG ALSO PREPARE PRODUCTIVITY ESTIMATES FOR THE PERIOD 1990 – 2001?**

A. Yes, in response to a data request to update its work, PEG updated the productivity study (AG-9-1 supp.) to include 2001 data. PEG did not update as requested for 2002, the test year in this case. The updated study produced productivity growth rates that were closer between gas utilities and the U.S business sector, as the two productivity measures differed by only 0.35 (rather than 0.45) percentage points annually over the period 1990-2001. This was a result of three changes.

First, the BLS has revised its 1990-2000 estimate of TFP, so that the differential between the gas and the total business productivity decreased to 0.42%, even if 1990-2000 were still used as the basis for comparison. Second, overall business productivity fell in 2001, reducing the growth rate of total business productivity. Finally, the productivity trend for the sampled gas industry increased when the year 2001 was added.

I would note also that the magnitude of the change -- from 0.45 to 0.35 – with the addition of a single year's data (as well as the other revisions) indicates how sensitive Dr. Kaufmann's analyses can be to the core assumptions.

Q. **HAS DR. KAUFMANN AGREED THAT THIS REVISED PRODUCTIVITY DIFFERENTIAL SHOULD BE USED IN THE X FACTOR?**

A. In the data response, Dr. Kaufmann argues that the major reason for the change is the decrease in total business productivity, which he attributes to 2001 being a recession year. Presumably he does not object to correcting the 1990-2000 results.

Q. **DO YOU THINK THAT DR. KAUFMANN HAS ESTABLISHED THAT A PRODUCTIVITY GROWTH DIFFERENTIAL BASED ON 1990-2000 IS THE APPROPRIATE VALUE TO BE APPLIED IN THE X FACTOR?**

A. No, he has not. The purpose of the productivity differential is to project the impact of the difference in the two productivity measures on prices over the next 5-6 years. This requires that the two productivity measures are comparable and indicative of the future relationship between them.

It is clear that annual measures of productivity vary considerably, largely because utilization of capacity changes as output changes. Thus, a medium to longer term review of productivity growth is necessary. However, in my opinion a computation of the relative changes in productivity between the gas industry and the entire business sector from 1990 to 2000 is not an appropriate methodology for projecting the relationship in the near future, in the absence of a clear demonstration that 1990-2000 growth in productivity is indicative of normal future growth for the total business sector or for the gas industry. Indeed, I believe that there is evidence to the contrary.

Q. **WHAT IS YOUR BASIS FOR ARGUING THAT THE 1990-2000 GROWTH IS NOT NECESSARILY INDICATIVE OF PRODUCTIVITY GROWTH FOR THE TOTAL BUSINESS SECTOR?**

A. First, Dr. Kaufmann has proposed to use change in productivity between the year 1990 and the year 2000 for the total business sector. His rationale for this period is that it compares the peak of a business cycle with the peak of the next business cycle. If one compared productivity at a peak with productivity during a trough, output would be depressed during the trough, which will tend to create a measurement indicating low productivity. Dr. Kaufmann's rationale is correct and I agree with it. But I do not agree with his conclusion that the 1990-2000 productivity growth rate is the "normal" growth rate for the economy.

First, the 1990-2000 calendar year comparison is not exactly coincident with the timing of the business cycle, since the peak of the earlier period is described as July 1990, and the most recent peak is defined as March 2001. Of greater concern, however, is that the growth from 1990 to 2000 for the total business sector was extraordinary, and therefore may not be considered "normal" and indicative of the future. I have attached a page from the BLS website, Attachment LS-2, which contains BLS' estimate of the multi-factor productivity index from 1991 through 2001. It is evident that the 2000 index was very high and showed high growth from the previous year. We know that 2000 was near the end of an unprecedented period of growth. Given that most projections are that economic growth will be slower in the next five years, the 1990-2000 period seems likely to be overstating future productivity growth.

At a minimum, the Company needs to demonstrate clearly why this is not the case. It is essential that the approach taken to projecting the future must not be based upon extraordinary events or circumstances that are not likely to be repeated. This conclusion is hardly something that should be simply assumed.

Q. WHY MIGHT THE 1990-2000 PERIOD NOT REPRESENT NORMAL FUTURE GROWTH IN GAS PRODUCTIVITY?

A. There is no *a priori* reason to assume that gas utility productivity would move in concert, systematically, with total business productivity. The factors that affect overall long-run productivity, such as technological change and economies of scale or scope, would be expected to have an impact on actual gas productivity. However, measured annual gas productivity will change fundamentally with the intensity of utilization of gas plant. And the intensity of utilization of gas plant will depend heavily on the relationship between gas prices and the prices of competing sources of energy, and on weather. When gas prices are low relative to oil and electricity, gas usage will increase. When the weather is cold, gas usage will increase. Neither the relationship between various energy prices nor the weather is related directly to the national business cycle.

Since gas delivery volumes are weighted heavily in the measure of output, variation in output as a result of relative prices or temperature will have a significant impact on measured productivity. PEG does not indicate that it took into account the impact of weather on the time period over which productivity was measured, or the impact of relative energy prices.

According to the EAIA, gas prices were much higher relative to oil prices in 2000 than in 1990. Specifically, gas prices were 45% of oil prices in 1990, but climbed to 73% of oil prices in 2000. All else being equal, the magnitude of this relative change can be expected to lead to a reduction in gas use (or, more likely, a reduction in its rate of growth).

There may also be a relationship between new housing construction and the number of customers and of gas usage, and new housing construction may not follow the business cycle. Finally, the timing of traditional rate cases may impact utility inputs, if some utilities increase their investment in what become test years.

PEG's gas productivity analysis would clearly be affected by the factors described above. Thus, a decrease in productivity as measured by this analysis may be explained by warmer weather or by a large switch by dual fuel customers from gas to oil in the latter year of the study, rather than by a "real" decrease in productivity.

Q. DO YOU HAVE ANY OTHER REASON TO QUESTION THE ACCURACY OF THE GAS INDUSTRY PRODUCTIVITY STUDY?

A. Yes. In Section V, I discuss factors that call into question the accuracy of the measurement of the capital input data used in both the cost study and the productivity study. In response to AG 3-40, the Company has provided separate computations of labor productivity, capital productivity, and other O&M input productivity trends. These indicate a 4.08% growth in labor productivity and a –0.47% for capital productivity and a –0.22% trend for other O&M inputs. The negative trend in capital productivity would have had a significantly depressing effect on the total factor productivity. If problems with the capital input data caused growth in this factor to be overstated, this could have depressed the total industry productivity.

Q. FOR PURPOSES OF ESTABLISHING A PBR FORMULA, WHAT IS THE IMPORTANCE OF A DIFFERENT PATTERN OF CHANGE IN PRODUCTIVITY BETWEEN THE PRIVATE BUSINESS SECTOR AND THE GAS INDUSTRY?

A. If the change in measured short-term productivity in the business sector and in gas utilities is caused by different factors, there is no reason to assume that the relationship between productivity growth observed in the total business sector and the gas sector in one period will apply to another period. For instance, if the relationship between gas prices and other fuels changed during the course of a business cycle, such that it influenced the change in productivity in the gas industry, data from that business cycle might not be useful in predicting the relative change of productivity in the future. This would, in turn, affect the value (and perhaps the sign) of the X factor in the PBR formula.

Q. ARE THERE OTHER DATA THAT SUGGEST A DIFFERENT RELATIONSHIP BETWEEN THE TOTAL BUSINESS SECTOR AND THE GAS INDUSTRY?

A. First, there are data from the BLS itself. The BLS reports that the compound annual rate of growth in productivity in the entire utility services industry was 0.8 % from 1990-1998. This, however, reflects the productivity gains from all utilities. During this same period, the productivity growth in the total business sector was 0.89%. If the total utility industry was indicative of the behavior of gas utilities, then the difference in productivity would be only 0.09%.

Second, there is a relatively long recent period in which many utilities in several states have survived and in some cases prospered with no increases in their delivery service rates. While many of these have been electric utilities that agreed to cap rates as parts of restructuring plans, the components of delivery service are not dramatically different between gas and electric utilities. Both are capital intensive industries, and both provide customer service and operate and maintain delivery systems.

Q. IF THE COMPANY'S STUDY IS NOT AN ADEQUATE JUSTIFICATION FOR THE CLAIMED PRODUCTIVITY DIFFERENTIAL, WHAT CAN WE ASSUME ABOUT PRODUCTIVITY?

A. In the absence of strong evidence to the contrary, I recommend that the Department assume that, absent PBR, the gas industry would experience productivity growth similar to productivity growth in the private business sector. The following factors will contribute to productivity improvements in the gas industry:

1) Technological improvements, such as better materials, improved pipe laying equipment, new techniques for detecting leaks, new techniques for repairing pipe without digging;

2) Improvements in information technology that impact metering, billing, record keeping, and the use of Geographic Information Systems to better map the system;

3) Mergers which should, in time, produce economies of scale.

IV. ANALYSIS OF INPUT PRICE DIFFERENTIAL

Q. WHAT HAS PEG DONE TO ESTIMATE THE DIFFERENCE BETWEEN INPUT PRICES IN THE GAS INDUSTRY AND INPUT PRICES IN THE OVERALL ECONOMY?

A. The growth rate in the Northeast gas industry was computed by weighting growth rates in capital services, labor, and non-labor O&M inputs. The capital services were the same estimated capital services values used in the productivity study.

In response to AG-9-2, PEG calculated that the differential in growth between Northeast gas input prices and overall prices was 0.3% between 1990 and 2001. In the original study, they found that input prices for Northeastern gas utilities increased by 3.02% annually over the 1990-2000 period, while input prices for the economy grew at rate of 3.10%. In both periods the input price differential produced a positive impact on the X factor -- meaning that gas input prices have increased more slowly than the overall price index.

The higher differential when 2001 is included is attributed by PEG to lower interest rates and returns to capital in 2001. Since the gas industry has a higher proportion of capital costs than the overall economy, a lower cost of capital has more impact on the gas industry than on the overall economy. Since interest rates and returns to capital have not risen in 2002, it is unlikely that even more updated numbers will decrease this differential.

Q. WHAT SHOULD BE UTILIZED FOR THE INPUT PRICE DIFFERENTIAL?

A. Since gas can be expected to remain a capital intensive industry, its input prices for the next five years will be primarily influenced by the cost of capital. While I do not expect the cost of capital to rise quickly, it is still at a low level and is unlikely to decrease further. Because of the lack of clear data, and to be conservative, I recommend that we assume that gas input prices change at the same rate as average system prices.

Q. WHAT IS THE COMBINED RESULT OF YOUR RECOMMENDATIONS REGARDING BOTH THE RATE OF CHANGE IN PRODUCTIVITY AND THE RATE OF CHANGE OF INPUT PRICES?

A. Since I do not think there is evidence clearly supporting the existence of continuing differences between the gas industry and the overall economy, this means that the PBR formula "defaults" to the GDP-PI less the consumer dividend.

V. PROPOSED CONSUMER DIVIDEND

Q. WHAT HAS PEG PROPOSED AS THE CONSUMER DIVIDEND?

A. The proposed X factor includes a consumer dividend of 0.15 percentage points, which is quite small. If the consumer dividend were the only adjustment to the GDI-PI, it would result in gas prices increasing just slightly less than general prices. The proposed consumer dividend and the price input differential together are not large enough to overcome the negative impact of the productivity differential. As a result, under the Company's formula, gas rates would increase faster than the general inflation rate.

Q. WHAT IS DR. KAUFMANN'S RATIONALE FOR RECOMMENDING A CONSUMER DIVIDEND OF ONLY 0.15%?

A. Dr. Kaufmann makes two arguments: that a utility that already is a "superior cost performer" (which he claims Boston Gas is) has less room to cut costs than other utilities, and that a Company "that has previously been subject to PBR will likely have less ability to reduce its costs" than utilities that had not been subject to PBR. Dr. Kaufmann testifies that for some companies the most appropriate value for a consumer dividend is zero, because those companies are more efficient to start with and because there may be other benefit sharing mechanisms.

Q. WHAT IS THE BASIS FOR THE CLAIM THAT BOSTON GAS IS A HIGHLY EFFICIENT COST PERFORMER?

A. One of PEG's analyses is an econometric model of gas utility costs, in which the cost drivers are factors that are expected to be out of a company's control, such as input prices, outputs, variables reflecting the proportion of electric customers served, and the percentage of mains that are cast iron. The model also includes dummy variables for the Northeast and for earthquake territory. The results are based on 42 utilities over the period 1993-2000. In response to a data request, they also updated the study to include 2001.

Q. PLEASE DESCRIBE THE COST ANALYSIS IN MORE DETAIL.

A. The cost study is an econometric analysis which assumed that the minimum cost for a utility was a function of the utility's outputs, the price of its inputs, and a number of "business condition" variables, which included the percentage of distribution main that is not cast iron, the number of electric distribution customers, a trend variable, and dummy variables for earthquake-prone territory, for the Northeast, and for Boston Gas only in the years in which it was subject to PBR previously. The form of the analysis is a translog function, based on logarithmic values. The equation was also "augmented" with equations regarding cost shares. A Feasible Generalized Least Squares approach was also iterated many times to address problems caused by contemporaneous correlation.

Q. WERE YOU ABLE TO RUN ALTERNATIVE VARIANTS OF THE COMPANY'S COST MODEL?

A. No. As may be evident from the brief summary above, the model was extremely complex. The Company would not provide this model in response to discovery, stating that it could only be used on a mainframe computer if the offices of PEG. The discovery responses provided generally did not illustrate how even basic computations were made. As a result, the cost projection remains very much a large "Black Box".

Q. HAS PEG USED OTHER VARIABLES IN OTHER PROJECTIONS OF GAS COSTS?

A. Yes. In the 2001 study performed for the TXU and Evestra utilities in Australia (Data response AG12-14), using a sample that was very similar to that utilized in the Boston Gas study, explanatory variables included the percentage of total main (transmission and distribution) that was distribution main, the percentage of customers who were non-industrial, and excluded all of the dummy variables utilized for the same type study for Boston Gas.

Q. DO YOU AGREE THAT BOSTON GAS' COSTS INDICATE THAT IT IS VERY LOW COST UTILITY AND IS UNABLE TO IMPROVE ITS EFFICIENCY?

A. I don't think that the PEG study demonstrates that Boston Gas' has already achieved great efficiencies. The study does demonstrate that when "costs" and "outputs" are defined in a particular way, and that when certain other variables are used to predict "costs" defined in this way, Boston Gas appears to have lower costs than the minimum costs which the model predicts it would have. However, if the modeling effort has misinterpreted Boston Gas' costs, and the cost model underprojects Boston Gas costs, then the model finding should be given little or no weight.

Q. DOES THE MODEL UTILIZE OR SAY ANYTHING ABOUT ACTUAL BOSTON GAS COSTS?

A. No. The predicted costs were compared to costs computed by PEG, based on actual booked labor costs, actual O&M less gas costs, and PEG's interpolation of normalized utility capital costs. The booked labor and O&M costs do not include all of Boston Gas' costs, as they reflect the SEC allocation of administrative and general costs. But in actuality, Boston Gas' rates will reflect a larger amount of A&G costs. The capital costs in the studies provided to date do not include the large amount of capital additions made in 2002. Moreover, the entire definition of the capital cost depends on extensive vintaging, which is poorly supported, and on a uniform treatment of carrying costs for all utilities in the study.

Q. PLEASE EXPLAIN WHAT YOU MEAN BY "THE DEFINITION" OF CAPITAL COSTS.

A. In order to estimate how capital costs compared across different utilities, PEG attempted to restate actual capital costs so that they were consistent across utilities. This should result in plant being valued based on its economic value, rather than simply its book value. Older plant may be booked at the very low cost which reflects its installation cost, and this booked number will usually understate the service that the plant provides. If there was no adjustment, the utility with older plant would always appear to be a low cost utility. This would be due not to its efficiency, but to the fact that its plant was old. To attempt to compare efficiencies across utilities, capital costs must be adjusted. PEG first restated the net book value of plant, as described above, and then estimated capital carrying costs and applied them to each utility's restated value of plant.

Q. DID YOU FIND PROBLEMS IN THE MANNER IN WHICH PEG MADE THESE ADJUSTMENTS TO DEVELOP CAPITAL COSTS?

A. Yes. For one thing, PEG began with 1983 booked plant for each utility, and adjusted each apparently by the same adjustment for vintage (although the adjustments varied slightly between utilities to reflect regional construction cost differences), based on the Handy Whitman index of the total value of gas utility plant. This took no account of the different average age of plant in 1983. It also took no account of differences in the makeup of plant across the utilities, since plant value was adjusted on a total basis rather than account by account. According to the response to AG 30-17, PEG did not perform an analysis to determine if there were differences between utilities in the relative value of different plant accounts. There are considerable differences in the Handy-Whitman rate of change by plant account. For instance, in the 20 years between 1963 and 1983, the index for cast iron mains increased by a factor of 4.4, while the steel mains index increased by 6.8, and the index for meters increased by only 2.9. Since each utility has a different proportion of total plant in these different plant accounts, indexing based on a single total plant adjustor cannot be accurate. If the plant vintaging is not accurate, then the entire estimate of capital costs will be inaccurate.

Q. WERE THERE OTHER PROBLEMS WITH THE COST STUDY?

A. Yes. I believe there may be significant cost causative factors which have not been included, and that the lack of these factors would tend to make Boston Gas look like an efficient performer.

Q. WHAT ARE THOSE FACTORS?

A. While there are a number of causative variables that might be modified or added, the most important seem to be the rate of expansion of the distribution system and the density of customers on the system.

Q. PLEASE EXPLAIN WHY THE RATE OF EXPANSION OF THE DISTRIBUTION SYSTEM MIGHT AFFECT COSTS.

A. Adding distribution line in order to add new customers will frequently increase utility costs. I would expect that newer distribution utilities, and distribution utilities in areas with faster population growth and new housing construction, would tend to have higher costs than would distribution utilities in locations with slower growth which called for less distribution system growth. Boston Gas is in a slower growth region than most of the western and southwestern utilities. Although the number of customers is an explanatory variable, there will be a large difference in the cost of adding a customer on an existing distribution line and adding a customer who requires construction of new distribution line. The PEG model does not recognize this difference.

Q. WHAT IMPACT MIGHT DENSITY HAVE ON SYSTEM COSTS?

A. Systems that are more dense, e.g. that have more customers per mile, will need less length of main per customer, and maintenance of that main and meter reading will require less travel and therefore less time. I expect that Boston Gas' system is dense relative to the nationwide sample, so that if density is a cost driver, and were reflected in the cost projection model, this would almost certainly reduce Boston Gas' projected minimum costs.

Q. DID THE COMPANY INDICATE THAT IT TESTED A DENSITY VARIABLE?

A. Yes. In response to AG-12-17, it indicated that it tested a number of other explanatory variables, including miles of distribution main divided by numbers of customers, but that this variable was not statistically significant at the 10% level.

Q. DOES THAT RESPONSE DEMONSTRATE TO YOU THAT DENSITY IS NOT A COST DRIVER?

A. No. Another measure of density might have produced better results. The variable may not have appeared significant because of other variables included in the equation.

Q. WHAT IS THE SIGNIFICANCE OF POSSIBLE FLAWS IN THE COST PROJECTION MODEL?

A. The model provides the only quantitative analysis to support the Company's claim that its very low consumer dividend is appropriate. If the model has overprojected Boston Gas' costs, this support for the consumer dividend dissipates.

Q. DOES MR. BODANZA SUPPORT THE PROPOSED X FACTOR IN HIS COMMENTS ON THE RELATIONSHIP BETWEEN THE PREVIOUS PBR PLAN AND THIS ONE?

A. Mr. Bodanza states that the fact that the Company now shows a revenue deficiency "tends to indicate" that the previous PBR didn't adequately account for cost increases and may have overstated potential productivity growth.

Q. DO YOU AGREE WITH HIS STATEMENT?

A. No. The facts are that the Company last received a rate increase resulting from PBR on November 2001, and that it is now requesting a rate increase of 18% of distribution rates. However, we can be fairly certain that its final revenue requirement will turn out to be less than the amount it has been asking for. To start with, as explained by David Effron, the requested increase of $61 million includes at least $7.5 million in Service Company costs that the Company allocated to the operations of Colonial Gas, and which have been added back in to Boston Gas' costs. We would not expect the PBR to anticipate and cover for these "add in" costs. Adjusting for these reduces the requested shortfall to $53.8 million. Next, the Attorney General and other intervenors are disputing the requested increase. If Boston Gas receives 50% of the $53.8 million, this will result in a rate increase of 8%. This increase will be first applied to a rate year from October 30, 2003 to April 30, 2004. If the PBR plan had continued, the Company would have received two rate increases before the end of the rate year, on November 2002, and November 2003. This would have resulted in a total increase of approximately 4.5%.

If PEG's cost study is correct, this number would have been lower if PBR had been in effect. For this increase, however, according to the Company, it is now providing improved outputs. Mr. Bodanza has testified that the Company actions over the last two years have provided customers with different products and improved reliability. Unless this level of service change continues, we should not see a continuation of the incremental costs that provided these service level changes. This suggests that the previous PBR did not do badly; in spite of going through several mergers, introducing new products, and improving service reliability, the difference between the PBR level of rates and what is likely to result from this case is not very large.

In addition, Mr. Bodanza's suggestion that the PBR didn't adequately account for cost increases and may have overstated potential productivity growth contains the assumption that during the period since the PBR ended the Company made the same level of effort to improve efficiency that it did during the PBR period. This is not a foregone conclusion, since during much of this period the prospect of a rate case with 2002 as a test year created incentives to invest in more capital additions and to not reduce staff.

Mr. Bodanza argues that the cost savings associated with the Company reorganization under QUEST and resulting from the merger "are captured in the test year O&M levels" and therefore it will not be possible to achieve the efficiencies that the Company achieved during the first PBR term. Further, Mr. Bodanza states that the low Consumer Dividend proposed by the Company "recognizes that productivity gains during the first PBR term are likely to be greater than those in successive terms." (Bodanza testimony p.24)

Q. ARE MR. BODANZA'S CLAIMS REGARDING ACHIEVED EFFICIENCIES AND THE COMPANY'S INABILITY TO MAINTAIN THE PAST LEVEL OF PRODUCTIVITY GROWTH SUPPORTED BY FACTS?

A. No, they are not. It is only a theory espoused by Mr. Bodanza and by Dr. Kaufmann. It is also possible, and it is my expectation, that productivity gains will accelerate as the Company continues, as a result of the merger, to adjust its operations and to react more efficiently to technological change, and to be guided by the incentives created by PBR. The Company has described new products and services that it is offering as a result of the merger, and described the implementation of "best practices", but it has not put forth evidence that it has made a significant reduction in the overall level of administrative and general employees or administrative and general expense (which is the first place where we would expect to see merger savings) as a result of the mergers.

Q. DO YOU AGREE THAT BOSTON GAS CANNOT FIND SIGNIFICANT ADDITIONAL EFFICIENCIES BECAUSE IT WAS UNDER RATE CAP REGULATION FROM 1997 -2001?

A. No. This implies that in this brief period Boston Gas made most of the improvements in efficiency that were possible and that may become possible in the future. This is highly unlikely. The merger may have even resulted in an increase in costs in the short run, as the Company integrated staffs and changed operations. I would expect that it would take time to make significant changes in its operations and to reduce staff that becomes unnecessary because of the consolidation.

Q. WHAT IS YOUR CONCLUSION REGARDING THE CONSUMER DIVIDEND?

A. First, the PEG study does not provide real evidence that Boston Gas is an efficient performer, or that it cannot become more efficient. Second, the previous PBR plan did seem to "work" for the Company.[2] Third, the large percentage increase requested by the Company will reverse benefits that may have been provided to customers by the previous PBR.

VI. EXPECTED BENEFITS FROM PBR

[2] According to the attachment to MDFA-3-8, the Company earned ROE's of 12.75%, 14.81%, 13.25%, 13.34%, and 1.47% for the test years 1996- 2000.

Q. DO YOU BELIEVE THAT THE DIFFERENCE BETWEEN EFFICIENCY UNDER COST OF SERVICE REGULATION AND EFFICIENCY UNDER PBR CAN BE CAPTURED IN A SHORT PERIOD OF TIME?

A. No. For one thing, if PBR is effective in changing management incentives, this will have an impact not only on how existing operations are performed, but also on how the utility will react to technological change. This latter benefit of PBR may even be more important than simply restructuring the existing operation. Changing the existing operation will be primarily a matter of determining that a number of existing functions can be simplified, and some existing labor can be eliminated, while producing the same output. We have observed that the electric distribution companies reduced their labor forces significantly from about 1996 to the present, when faced with competitive pressures and with rate caps. With PBR -- in either the gas or electricity businesses -- we should expect to see a different approach to change, to technological improvements in capital and even to the labor force.

Q. COULD YOU ILLUSTRATE THIS CONCEPT WITH AN EXAMPLE?

A. Yes. Under cost of service regulation, a utility faced with a technological change that had the potential to reduce costs would consider whether it was certain that regulators would allow recovery. The utility would have an incentive to delay implementation of such change until a likely "test year", so that it would quickly place any investment in rate base. If the investment was labor-saving, the utility would not have a strong incentive to reduce its labor immediately. Under PBR, there would be incentives to make the technological change more quickly and to reduce labor costs quickly if possible.

Q. HAVE THERE ALSO BEEN STRUCTURAL CHANGES THAT WE WOULD EXPECT TO RESULT IN GREATER EFFICIENCIES?

A. Yes. The series of mergers that have resulted in Boston Gas becoming a part of a much larger company, with a larger operation in Massachusetts, should also result in cost reductions. Regardless of what one might expect as a theoretical matter, it is reasonable to assume that these mergers would result in certain efficiencies and scale benefits that would lead to overall cost reductions. The Company has claimed that the mergers will result in a more efficient utility, although we do not have clear evidence that this has actually occurred.

Q. WHAT HAVE OTHER STATES DONE REGARDING PBR FORMULAE?

A. There are actually very few states that are applying PBR ratemaking to gas delivery rates, or even to electric delivery rates. All of those that I am familiar with include consumer dividends of some sort that produce rate increases less than the expected inflation in utility costs. Some states apply PBR to gas supply rates rather than delivery rates, which is not relevant here. The California Public Utilities Commission ("CPUC") has perhaps the most experience in applying PBR to gas utilities delivery rates.

Q. IS THERE ANY THEORETICAL JUSTIFICATION FOR ADOPTING PBR IF IT RESULTS IN A ZERO CONSUMER DIVIDEND, WHICH DR. KAUFMANN ARGUES IS POSSIBLE?

A. No. It is fundamentally inconsistent with the rationale for Performance Based Ratemaking. If the utility cannot be expected to improve its productivity growth rate under PBR, there is no justification for utilizing PBR rather than standard cost of service ratemaking. The Company has not demonstrated that its proposed PBR is better for customers than cost of service ratemaking. PBR creates a risk that customers will pay more than they would under cost of service ratemaking (in other words, more than reasonable costs), so it is particularly important that this risk be balanced by the possibility of significant benefits. Without the assumption that growth in utility efficiency will increase as a result of this changed ratemaking methodology, there is no appreciable benefit resulting from adopting PBR. In response to AG-30-2, the only potential dollar benefit that Dr. Kaufmann presented was that PBR would avoid the cost of yearly rate cases.

Q. WHAT RISKS OF PBR WERE YOU REFERRING TO ABOVE?

A. There are two types of risks. First, there is the risk resulting from projecting how much gas utility costs will increase. As the discussion earlier illustrated, there is a huge amount of data and assumptions involved in selecting an appropriate estimate of "normal" gas utility cost increases; in addition, there is an unsupported assumption that the same cost inflator will remain appropriate into the future. If all else is equal and if the escalation factor that is chosen is higher than the actual results of gas price input increases and gas productivity decreases, customers will pay more under PBR than under standard ratemaking.

In addition to concern about the rate of increase, the PBR plan will be in place for five years, so any overstatement in the initial revenue requirement that is the basis for "cast off" rates will be magnified over time. The harm to customers that could result from setting initial rates "too high", and then being inflated too rapidly will be somewhat mitigated by the Earnings-Sharing mechanism, but it is not eliminated.

Q. IS THE RISK THAT THE RATE OF NORMAL INCREASE WILL BE OVERSTATED EQUAL TO THE POSSIBILITY THAT THE RATE OF NORMAL INCREASE WILL BE UNDERSTATED?

I do not think so. Mr. Bodanza refers to a "perfectly structured" PBR Plan. (Exh. KEDNE/JFB-1, p. 23), which presumably would indicate exactly how to estimate normal rate increases and would provide a share of cost reductions to customers. In considering how these estimates are developed, I believe it is very unlikely that there will be symmetrical risk. Such a perfect structure would have to begin with a perfect estimate of how much gas utility costs should increase in the absence of PBR. The utility does not have the incentive to produce this perfect estimate, and the utility has the upper hand in making such an estimate. Even without considering the consumer dividend, the X factor computations are highly dependent on complex analyses and are very data intensive. The Company has ready access to the data and the resources to put together its case, while the DTE and the intervenors do not. Thus there is more likelihood that if rates are determined by an estimate of increase in gas company prices, or indexed, the indexing will overstate costs than that it will understate costs.

Q. IS THERE ANY QUANTITATIVE EVIDENCE AS TO ACHIEVABLE IMPROVEMENTS IN PRODUCTIVITY, OR CONSUMER DIVIDENDS?

A. Yes. The PEG cost study itself found that in the three years in which PBR was in place, Boston Gas costs were less than projected by the other cost drivers in the model. In other words, a dummy variable for the Boston Gas PBR produced a value of negative 0.3%. When the study was updated to include 2001, the variable was slightly less negative.

In addition, there is evidence from the experience of a number of other states, primarily from electric utilities, that have PBR plans with X factors of more than +1.0%. In Maine, for instance, CMP has been functioning under such a plan since 1995. In Pennsylvania, virtually all of the electric companies have functioned under distribution rate caps since 1998, without signs of distress.

The evidence that appears most applicable to this case is out of California. San Diego Gas and Electric ("SDG&E") and Southern California Gas ("SoCal") have functioned under gas distribution rate PBRs since 1994 and

1997 respectively. Both utilities have earned within a reasonable range of their authorized Return on Equity, despite an average consumer dividend of more than 0.6 %.

Q. PLEASE DESCRIBE THE SDG&E EXPERIENCE IN MORE DETAIL.

A. In SDG&E's most recent base rate case, in 1999, the CPUC adopted a PBR mechanism that features a rate indexing formula. Under this formula, gas delivery rates in Year N are equal to rates in Year N-1 multiplied by a gas utility input price escalation inflation factor less a productivity factor. The gas input price escalation factor is calculated annually based on changes in gas utility industry labor, non-labor, and capital-related costs. These three factors are weighted using California gas utility weighting percentages. The CPUC determined that the use of industry specific data to establish the inflation factor is superior to using a national aggregate price index, such as the CPI, because CPI-type indices are not designed to provide a framework for analyzing changes in the price level of inputs purchased by utilities. Using the above described methodology, inflation was estimated at 4.23% for 2000, 3.27% for 2001 and 2.48% for 2002.

Since the California PBR model begins with an input price index, whereas in Massachusetts the computation begins with an output price index, in California the input price index is adjusted for expected increases in productivity under normal (cost of service regulation) conditions. This is because costs go up by the increase in input prices less improvements in productivity.

The normal or "historic" productivity factor was developed based on a historic gas industry-wide study of total factor productivity. California's formula added to the historic productivity increase a consumer dividend, which they call a "stretch factor", that increased over the term of the PBR mechanism. For SDG&E this factor went from 0.4% to 0.7% over the 5 year period of the PBR, averaging 0.55%. For SoCal, this factor was 0.6% in 1999 and rose to 1.0% five years later. The CPUC justified increasing the consumer dividend by noting that productivity improvements do not occur all at once, but take time to implement.

Earnings associated with rate increases that fall outside of a 25 basis-point deadband above the authorized rate of return (for the combined electric and gas departments) are shared among shareholders and customers in accordance with a progressive sharing mechanism. The customer portion of those earning are flowed to customers through an adjustment to the next year's rates.

Q. DOES SDG&E'S PBR MECHANISM INCLUDE OTHER PERFORMANCE MEASURES?

A. Yes, it does. These performance measures are designed to ensure that SDG&E's service quality, customer service, reliability, and safety do not deteriorate under PBR regulation. SDG&E's performance is reviewed according to certain criteria and either earns a reward or suffers a penalty. These rewards and penalties, which are in addition to any earnings achieved under the rate indexing formula, are also recovered through an adjustment to the next year's rates.

Q. WHAT HAS BEEN THE EFFECT OF RATE INDEXING, AND IN PARTICULAR THE ADOPTED PRODUCTIVITY FACTORS, ON SDG&E'S FINANCIAL PERFORMANCE?

A. As of this time, results for the first two years of SDG&E's PBR mechanism have been filed with and approved by the CPUC. For the first year, SDG&E recorded a combined ROR of 9.28%, which is 23 basis points above the weighted authorized ROR of 9.05%. Thus, there was no sharing of the excess earning in the year one. In year two, SDG&E recorded a combined ROR of 8.74%, which is slightly below the authorized ROR of 8.75% for that year. Consequently, no portion of SDG&E was subject to the sharing mechanism. These results demonstrate that SDG&E's financial health was not jeopardized by the adoption of the consumer dividends that average 0.55%, resulting in rates which increased 0.55 percentage points less than a gas inflation index.

VII. RECOMMENDATIONS

Q. WHAT ARE YOUR RECOMMENDATIONS WITH REGARD TO THE PROPOSED PBR?

A. Since that the Company has not demonstrated the appropriateness of its proposed X factor, and in particular given the absence of a consumer dividend, I recommend rejection of the proposed PBR plan and a return to cost of service regulation of the Company's rates. However, if the DTE finds that PBR is warranted, I recommend utilizing the same formula that was utilized in the previous PBR plan. There is no clear demonstration that gas utility productivity will increase more slowly than general inflation, and although gas input prices have increased at less than overall input prices, that difference has been very small and will not necessarily continue. There is evidence supporting a consumer dividend of from 0.3 to 0.7%. Taken together, rates should change at the rate of the Gross Domestic Price Inflator less 0.5%. The proposed Earning Sharing mechanism should also be adopted.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes it does.